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The life cycle greenhouse gas implications of a UK gas supply transformation on a future low carbon electricity sector

Geoffrey P. Hammond ^b, Áine O' Grady ^{a,*}

^a Department of Mechanical Engineering, University of Bath, Bath, BA2 7AY, UK

^b Institute for Sustainable Energy and the Environment, University of Bath, Bath, BA2 7AY, UK

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ABSTRACT

Natural gas used for power generation will be increasingly sourced from more geographically diverse sites, and unconventional sources such as shale and biomethane, as natural gas reserves diminish. A consequential life cycle approach was employed to examine the implications of an evolving gas supply on the greenhouse gas (GHG) performance of a future United Kingdom (UK) electricity system. Three gas supply mixes were developed based on supply trends, from present day to the year 2050. The contribution of upstream gas emissions – such as extraction, processing/refining, – is not fully reported or covered by UK government legislation. However, upstream gas emissions were seen to be very influential on the future electricity systems analysed; with upstream gas emissions per MJ rising between 2.7 and 3.4 times those of the current supply. Increased biomethane in the gas supply led to a substantial reduction in direct fossil emissions, which was found to be critical in offsetting rising upstream emissions. Accordingly, the modelled high shale gas scenario, with the lowest biomethane adoption; resulted in the highest GHG emissions on a life cycle basis. The long-term dynamics of upstream processes are explored in this work to help guide future decarbonisation policies.

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1. Introduction

Gas has been widely touted, by both academics and policy-makers, as a critical bridging fuel in society's transition to a lower carbon future [1,2]. Global organisations such as the *Intergovernmental Panel on Climate Change* (IPCC) and the *International Energy Agency* (IEA) see gas-fired generation as a vital bridging technology during this transition [3,4]. Gas is defined here as a gaseous combustible mixture of hydrocarbons, consisting largely of methane (CH₄), which may also contain colliery methane, shale gas and biogas. Compared to other fossil fuels, 'gas' contains the lowest quantity of carbon per unit energy of any fuel, i.e. it has the most favorable C:H ratio, leading to much lower carbon dioxide emissions during combustion. Moreover, gas-fired generation is an inherently flexible conversion technology; ideal for providing backup to intermittent power generation [5]. Accordingly, both gas power generation with and without 'Carbon Capture and Storage' (CCS) [6] have been proclaimed as key generation technologies in the UK's energy transition [2,7]. Serious doubts have been raised

over the future of CCS in the UK in the wake of the UK government scrapping a £1bn funding competition to help CCS reach full-scale development. Nonetheless, both the *Committee on Climate Change* and the *Energy Technologies Institute* have projected that failure to deploy CCS could double the cost of a low carbon transition [8,9].

Bringing primary fuel to a gas power plant requires many upstream processes, including extraction, processing/refining, and transport, all of which expend energy and material resources and result in the release of greenhouse gas (GHG) emissions. Additionally, significant fugitive methane emissions often occur during production activities, and during the transport and handling of the gas. A comprehensive review conducted by the *Sustainable Gas Institute* (SGI) [10], examining 424 papers in total, estimated a wide range in greenhouse gas emissions associated with different gas supply chains (both conventional and unconventional). The report estimated that the total gas supply chain emissions could range between 2 and 42 gCO₂eq/MJ (assuming a global warming potential of 34 for methane). Upstream emissions are not exclusive to gas-fired generation, indeed, all electricity generators come with such associated emissions, from coal generation to solar photovoltaics, although they vary depending on the nature of that given system. Gas-fired generation offers significant GHG saving on an

* Corresponding author.

E-mail address: a.o'grady@bath.ac.uk (Á. O' Grady).

Abbreviations

CC	Central Coordination
CCC	Committee of Climate Change
CCS	Carbon Capture and Storage
CHP	Combined heat and power
DECC	Department of Energy and Climate change
DUKES	Digest of UK Energy Statistics
EPSRC	Engineering and Physical Sciences Research Council
ESCO	Energy services company
ESI	Electricity Supply Industry
GHG	Greenhouse gas

GWP	Global-warming potential
HV	High voltage
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
LCA	Life cycle assessment
LNG	Liquefied natural gas
MR	Market Rules
NGO	Non-governmental organisation
PV	Photovoltaics
TF	Thousand Flowers
TP	Transition Pathways
UKCS	United Kingdom Continental Shelf

operational basis compared to coal, however, upstream emissions can vary greatly between gas source and geographical location [11]. Upstream processes will gain relative importance as the performance of combustion technologies improve over time and with increased penetration of CCS in the electricity sector. Consequently, it is hypothesized that the gas supply mix may have a considerable bearing on the cumulative emissions from the future UK electricity sector.

Since 2004, the UK has been a net importer of gas [12], relying increasingly on international gas markets. Gas will be increasingly sourced from more geographically diverse sites, and/or more unconventional sources, such as shale and biomethane. The reshaping of the gas supply, as explored in this paper, could lead to an increase in the life cycle emissions of gas-fired generation, which are not currently fully addressed by legislation. Presently, only domestic emissions are included in the national GHG inventory, neglecting all non-domestic upstream activities and associated emissions which would be connected to any product chain [13]. Accordingly, upstream GHG emissions associated with the gas supply have not been well accounted for by the UK government. Previous analysis by both the independent *Committee of Climate Change* (CCC) and the then Chief Scientific Advisor to the *Department of Energy and Climate Change* (DECC) have regarded total upstream emissions as 'fixed', and 'inconsequential' in terms of their contribution to overall life cycle emissions associated with gas-fired generation [14,15]. However, both DECC and CCC are wrong in this assertion given that UK gas upstream emissions are set to change over the coming years, in response to a large transformation of the gas supply, as domestic natural gas diminishes [16]. Furthermore, their contribution to the GHG performance of UK electricity will become increasingly significant, as upstream gas emissions rise and are contrasted against an increasingly decarbonised electricity sector.

Decarbonisation of the 'Electricity Supply Industry' (ESI) forms the cornerstone of the UK Government's strategy to tackle climate change, as part of its transition towards a low carbon economy [2]. Current decarbonisation policies may lead to a shift in practices and adoption of production routes with unintended adverse effects upstream, which would not be accounted for under current UK carbon budgets [17]. The effect of an evolving gas supply on the future GHG performance of the ESI has not been fully explored to date, with only the implications of the shale gas penetration been previously considered by others in the field [18]. Wider trends in the gas market have been overlooked, such as the possible introduction of biomethane and shale gas, or in the long-term, the potentially infiltration of Russian gas. Indeed, in a letter to the House of Commons' *Environmental Audit Committee*, the CCC highlighted the need to adequately capture the 'life cycle emissions

of shale gas and alternatives' in future evaluations of the UK's net carbon accounting [19]. In addition to addressing recognised gaps in knowledge [20], this work aims to inform policymakers of the potential implications a changing fuel supply, particularly the uptake from alternative sources such shale gas and biomethane out to 2050. Increased understanding of the intricacies and dynamics of future energy systems, will better frame future decarbonisation policies, avoiding unintended, adverse cause and effects. This work is founded upon earlier life cycle environmental appraisal of the UK ESI, it forms part of an ongoing research effort, evaluating and optimising the performance of various sustainable energy systems [17,24].

A consortium was established to examine the role of electricity within the context of 'Transition Pathways to a Low Carbon Economy' across nine university partners. This multi-disciplinary team developed three socio-technical scenarios or 'transition pathways' towards a UK low carbon energy system as summarised in Table 1 [25,26]. Each pathway was characterised by different dominant governance 'logics': driven by the market, central government intervention, and local community initiatives respectively. A full account of these pathways and their development can be found in Foxon (2013) [7]. Previously, an environmental appraisal was performed for the 'transition pathways' of the UK ESI on a life cycle basis [17]. Upstream emissions were calculated assuming present day static fuel supply chains, a limitation when assessing a future system. In this present study, the 'transition pathways' have been paired with three future gas supply mix scenarios, which were developed to examine the uncertainties, and impact of dynamic upstream processes on decarbonisation strategies.

2. Methods

2.1. Dynamic life cycle emissions approach

A more dynamic LCA methodology was applied in this paper to investigate the likely environmental implications of the gas supply fuel evolution out to 2050. Consequential (change-oriented) LCA methodology was chosen to investigate the environmental implications of these likely potential choices [27] over time, in order to limit risk when undertaking strategic technological selection. Consequential LCA evaluates the change in flows in respect to a given decision or market, and subsequently the corresponding change in environmental impact beyond the foreground system.

In this paper, the reduced availability of domestic natural gas supplies causes a shift in demand for new sources of gas, such as shale gas and biomethane. These gas resources have different associated activities and processes, outside the original boundary of

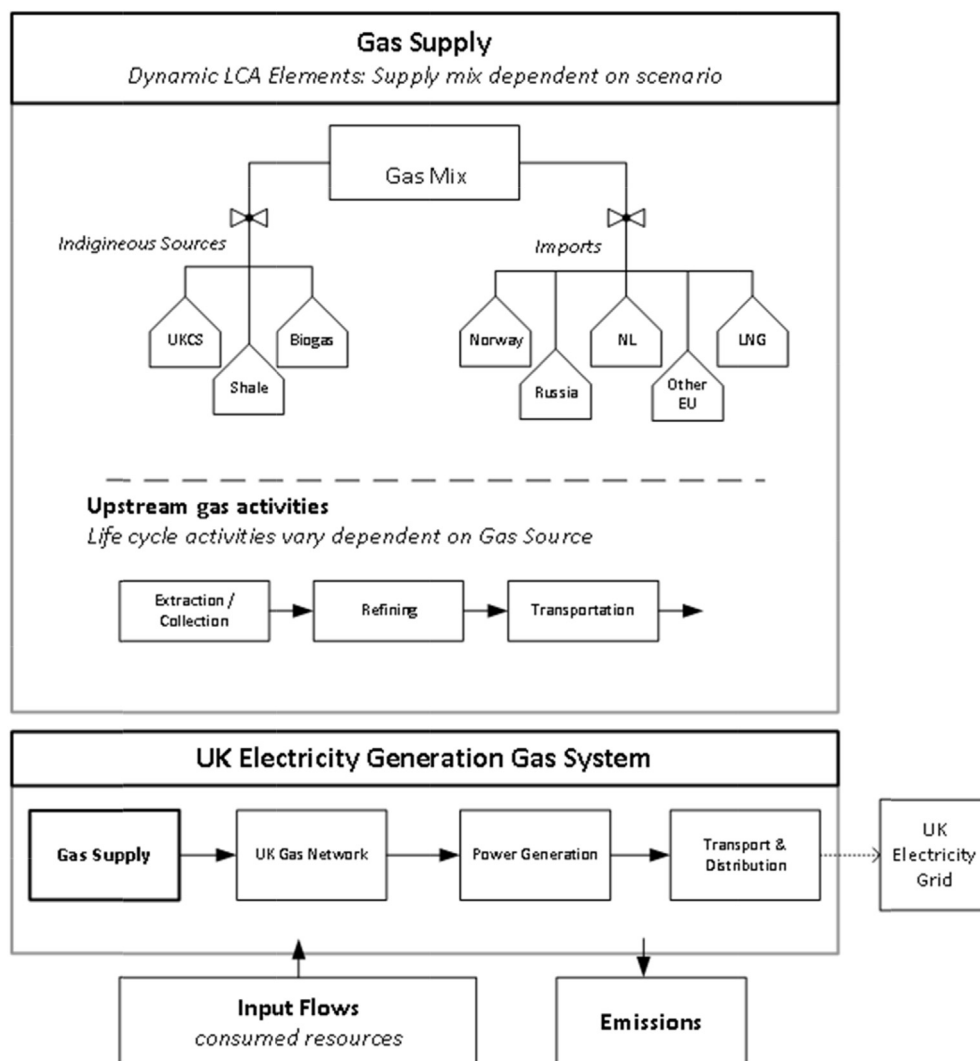
Table 1

Transition Pathways overview: adapted from Foxon [7].

	Market rules (MR)	Central co-ordination (CC)	Thousand flowers (TF)
Governance	Market logic	Government logic	Civil society logic
Key technologies	Coal and gas CCS; Nuclear power; offshore wind	Nuclear power; Coal and gas CCS; offshore wind	PV; Onshore & Offshore Wind; renewable Combined heat & power
Key trends	Limited interference in market arrangements; high level policy targets and high carbon price	Central government commission tranches of low-carbon generation from big companies to reduce risk of low carbon investment	Local, bottom-up diverse solutions led by local communities & NGOs, greater community ownership and more engagement of end-user
Electricity demand	Increase demand for heating and transport. Overall demand in 2050 (512TWh) much greater than today	Increase demand for heating and transport, but reduced through energy efficiency. Overall demand in 2050 (410TWh) slightly higher than today	Overall demand in 2050 (310TWh) lower than today. Higher rate of energy efficiency improvements and more aware consumers.

the product system (see Fig. 1), with a subsequent change in GHG emissions. The UK gas supply will depend on future contracts negotiated based on technical, political and economic factors. Ultimately, the consumed gas will be chosen based on the least expensive, most secure and viable supply chain. The implications of these potential decision-makers' choices for the future UK gas supply are explored in this study.

Both consequential and attributional methodologies of LCA provide valuable policy support [20–30] and can be applied when modelling future systems. Attributional LCA provides a broad overview of environmental consequences of a future system, whereas consequential LCA provides insight into the influences of decision makers, and the nature of a product chain on future systems. The insight provided by both methodologies are invaluable as

**Fig. 1.** System boundaries of the dynamic elements of the UK electricity generation gas system.

policy makers and regulators attempt to address multiple environmental goals. Together, they can provide a more rounded environmental assessment within a wider socio-techno-economic assessment framework [25]. Such analysis will help guide policy-makers and other stakeholders when investing in new generation technologies and considering their GHG performance as part of the energy policy 'trilemma' [7,31], i.e., the simultaneous delivery of low carbon, secure, and affordable energy services.

This analysis builds on the preceding attributional life cycle GHG assessment of the UK electricity system, from 'cradle to gate', for the three different *Transition Pathways*. In the baseline analysis, all data and assumptions were based on current prevailing technology, providing a static snapshot appraisal of the UK electricity system. A flowchart outlining the dynamic LCA approach adopted in this paper has been included in Appendix B below. The life cycle impacts of the UK power generators specified in these transitions, were determined using LCA datasets populated with real-life data compiled from current operational power plants. For more novel technologies, such as tidal and wave, proxy datasets have been adapted in accordance with studies of these technologies [32,33]. The coal and gas-fired generation datasets were adapted to account for the impact of *carbon capture* facilities, based on detailed studies of these technologies [34]. It was assumed that 90% of direct emissions were captured for both technologies, although coal CCS incurred a 23% energy penalty (average of the coal technologies examined), whilst gas CCS incurred a penalty of 17%. Due to the nascent nature of these capture technologies, it was difficult to obtain accurate data for the transport of the sequestered carbon and its final storage; therefore it was not included in the boundaries of the study. Appreciably, significant uncertainties arise when assessing a future system, such as potential technological advances and variations in fuel supply source over time. Here, the dynamics in the gas supply source (see gas supply box in Fig. 1) are explored to evaluate its potential implications on the GHG performance of the electricity sector.

The system boundaries of this assessment were defined as 'cradle-to-gate' electricity provision (see Fig. 1). All upstream processes were included from material extraction, manufacturing, transportation, and construction of the power plant. The downstream boundary was taken as the point of delivery to the electricity transmission grid. The *Transition Pathways* (version 2.1) were used as the basis for this investigation (i.e. the *baseline system*) into the gas supply evolution over time. The *Digest of UK Energy Statistics* (DUKES) allocation for fuel, which assumes that it requires twice the fuel to generate electricity as to produce heat [35], was used to allocate emissions associated with 'Combined Heat and Power' (CHP) plants. This allocation was used to reflect the resource's value as both an electricity and heat provider.

Three potential future gas mixes were developed to explore their impact on the future UK ESI emissions, based on projected gas trends, market developments, and future production insights, as outlined in Section 2.2. The three future gas mixes were paired with the three *Transitions Pathways* (in place of the 2012 gas supply mix), allowing their impact on a potential future UK ESI to be investigated through nine potential energy future scenarios. This analysis does not attempt to predict the future but rather explore the potential implications of an evolving gas supply on the GHG performance of three different UK electricity systems. Variation in gas supply is likely to result in knock-on changes to the pathways themselves. However these wider implications have not been considered in this study. The pathways have only been used here as a means of examining future UK electricity systems, and not assessing the full implications of an evolving gas supply on the future generation mix. The gas supply upstream systems (see Fig. 1) vary only in terms of their relative contribution to the overall gas supply, with all

underlying assumptions remaining the same out to 2050. The only exception is for biomethane production, where the feedstock mix evolved over time, although again, the underlying assumptions for each feedstock resource group remain unchanged.

The emission data for gas sources were reported in aggregate CO₂eq emissions based on IPCC AR4 GWPs over a 100 year time horizon, as published by the IPCC [36] [*Fourth Assessment Report* (AR4), 2007]. Emissions data could therefore not be updated to the more recent AR5 GWPs [37], as the contribution of each greenhouse gas to the overall total cannot be determined. Consequently, AR4 GWPs were applied across the system to maintain consistency. The system boundaries were aligned for all gas supply routes (see Fig. 1 in paper). Emissions were accounted from the extraction of gas (or cultivation of feedstock and collection of waste for biomethane), through processing (including liquefaction for LNG), long distance transport (where applicable), and finally the regional distribution in the UK to the gas-fired power plants. In order to limit the level of uncertainties in this analysis, it was assumed that the fuel supply chains (i.e. gas background systems/upstream processes) would remain the same as today's route based on current available data. The data used for upstream emissions associated with different gas supply routes as delivered to gas-fired power plant, can be seen in Fig. 2.

Emissions data for natural gas imported by pipeline from Norway, the Netherlands, wider EU continent and Russia were taken from the *Ecoinvent* database version 2.2 [38]. Monte Carlo simulations were carried out for each supply route in order to quantify the uncertainties related to each dataset. Given the infancy of unconventional gas in the European Union, it was assumed all gas from these regions would be derived from natural gas out to 2050. A review paper of the life cycle GHG emissions associated with shale gas production was used to account for this gas supply pathway [39]. Data was collated from various studies to produce an uncertainty distribution to represent the potential impacts of future LNG in the UK [38,40–43]. The origin of future LNG could vary significantly, depending on the gas markets and the international development in shale gas extraction. Again, it was assumed here that all LNG is from conventional sources in order to reduce the uncertainties. The median was chosen to represent the central tendency of the distribution of LNG gas in this study, instead of the average, in order to reduce the impact of outliers on the results due to the relatively small sample size of the data available. The methods used by the various studies to quantify uncertainty vary between gas sources, although the majority of sources (all pipeline natural gas, biomethane, and shale gas) were calculated based on Monte Carlo simulations. A confidence interval of 95% was used for

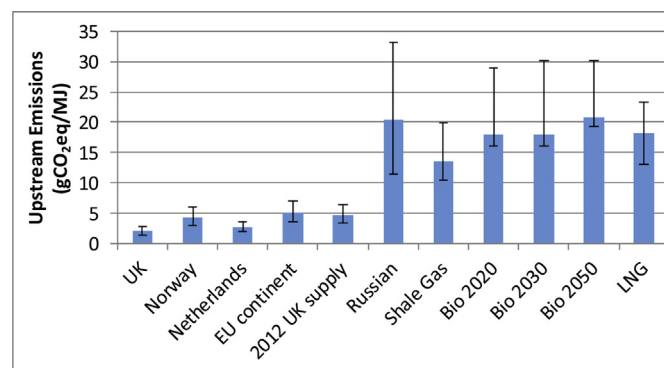


Fig. 2. Upstream GHG emissions associated with gas supply pathway by source [uncertainty ranges vary between gas sources as discussed in Section 2.1].

pipeline gas and shale gas, while a confidence level of 80% was employed for the biomethane gas pathways. A probability distribution was developed from the LNG data collated, where the uncertainty range represents a 95% confidence level. The future gas mixes uncertainty ranges shown in further figures was then calculated based on the proportion of each source that contributes to the overall mix.

The current UK feedstock mix for anaerobic digestion was employed when accounting for emissions associated with biomethane production. The 'energy focus' scenarios developed by Welfle et al. [44] of the UK bioenergy potential out to 2050, were used to model the change in feedstock contribution over time. The range in emissions for these mixes were calculated based on data from literature for these feedstocks [35,41]. The final stage of compression and dispensing of the gas was not included and was instead replaced by a biomethane injection stage as modelled by Adams et al. for the UK [45]. Biogenic carbon emissions emitted during the combustion of biogenic feedstock is equivalent to the carbon absorbed during the growing of that same feedstock. Where the cultivation of feedstock has been sustainably managed, it is considered a carbon neutral process over the course of the bio-energy system life cycle. Conventionally, as stated in the IPCC guidelines [46], such biogenic emissions are not accounted for within the energy sector, but rather anthropogenic variations in carbon stocks are accounted through land use change. Such an approach was adopted here in order to avoid double-counting of emissions. The biogenic emissions captured through use of CCS have been treated in the same manner as captured fossil emissions, and modelled as an offset, having being prevented from release into the atmosphere.

2.2. UK gas supply evolution

Whilst the UK's domestic natural gas production (mainly North Sea) has declined in recent decades, imports with greater associated upstream emissions, have risen to meet the shortfall. Since the UK government doesn't currently account for these upstream emissions within the electricity sector [13], the change in the true carbon intensity of the UK electricity grid mix on a life cycle basis has not been well documented. Demand has been reducing over the past number of years, particularly for electricity generators, due to the relatively high gas price compared to coal [47]. However, given its flexibility, relative short project lead in times, and low capital cost, gas-fired power generators are set to remain a major component of the UK electricity system for many years to come [48]. In fact, The UK government recently announced an energy

policy 'reset', which would see that all unabated coal-fired power stations were to close by 2025 [48], further emphasising the critical role of gas generation in the UK energy future. The baseline UK gas mix (as of 2012) can be seen in terms of percentage shares in Table 2. There are many external pressures at play which are likely to influence the UK market over the coming years [16,49–51], such as increasing Asian demand, diminishing reserves in the European Union, and growth in unconventional gas sources (such as shale gas and biomethane). Norwegian and Dutch production are set to decline post 2015 [52,53], leaving the UK progressively more reliant on imports of LNG and pipeline gas from mainland Europe, largely originating from the Russian Federation (Russian imports account for over 25% of consumed natural gas in Europe [54]). Furthermore, gas markets have proven to be rather susceptible to "black swan" events. These are low probability, high impact events that are hard to foresee [55]. The Fukushima nuclear disaster is a recent example of such an event, which resulted in a large demand for imported gas by Japan. Thus, in 2012, due to increased prices, UK LNG imports were down 50% than in the previous year.

2.3. Future UK gas supply scenarios

Three future gas mix scenarios have been developed, based on the future trends discussed in the previous section in order to explore the potential implications of a reshaping UK gas supply. A list of the main assumptions and background data used to develop the three gas supply scenarios are provided in Appendix A. These mixes have been developed for explorative means only, and do not attempt to predict or, particularly, imply the nature of the future gas market. Three sets of mixes have been generated for each supply scenario: a mix for years 2020, 2030 and 2050 respectively in order to explore the transition. The main assumptions and trends for each case study are outlined below, and their supply breakdown is provided in Table 2.

- **Supply 1: UK Shale gas 'boom'.** In this future, it is assumed that shale gas extraction takes off and becomes the UK's primary gas source. Reliance on other gas sources will reduce, with a stable contribution maintained in the interest of security of supply. In this future, it is assumed that LNG will be the main source of imports. Russian imports are reduced due to political tensions in that region. A moderate penetration of biomethane continues as part of the mix in order to utilise biowaste.
- **Supply 2: High biomethane and LNG supply.** In the event of a shale gas moratorium across the whole of the UK, biomethane would be more heavily developed to provide an indigenous

Table 2
Future UK gas supply mixes by source.

Source by percentage	2012	2020			2030			2050		
	Supply mix	Supply mix 1	Supply mix 2	Supply mix 3	Supply mix 1	Supply mix 2	Supply mix 3	Supply mix 1	Supply mix 2	Supply mix 3
UKCS	52.9	38.0	38.0	38.0	23.6	23.6	19	5.0	5.0	5.0
Biogas	0.0	5.0	10.0	5.0	5.0	18.0	5.0	5.0	25.0	10.0
Shale gas	0.0	9.6	0.0	0.0	34.4	0.0	0.0	60.0	0.0	0.0
Indigenous	52.9	52.6	48.0	43.0	63.0	41.6	24.0	70.0	30.0	15.0
Norway	25.9	30.4	30.4	30.4	20.6	20.6	20.6	140.0	14.0	14.0
Netherlands	6.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LNG	13.0	11.5	16.1	11.5	9.9	28.4	16.0	11.2	42.0	20.0
EU Continent	1.3	2.3	2.3	6.3	2.2	3.2	7.9	0.7	2.8	7.7
Russian	0.0	3.2	3.2	8.8	4.4	6.3	31.6	4.1	11.2	43.4
Imports	47.1	47.4	52.0	57.0	37.0	58.4	76.0	30.0	70.0	85.0
Total	100	100	100	100	100	100	100	100	100	100

supply of gas. Again, in this future, it is assumed that LNG will be the main source of imports. Russian imports were again reduced because of political tensions in that region.

- **Supply 3: High Russian gas dependence.** This future assumes a shale gas moratorium in the UK. Biomethane is also limited, due to various likely environmental pressures (such as land use). In the absence of a shale gas supply, and constrained biogas, it was assumed that domestic UK conventional natural gas supply will be conserved over time in the interest of security of supply. Asian demand for LNG also increases dramatically, constraining this source. Consequently, Russia would become a critical supplier to Europe.

3. Results

3.1. Life cycle GHG emission intensity of future potential UK gas supply mixes

The GHG emissions associated with the three future gas supply mixes out to 2050 are presented in Fig. 3. For all three supply mixes, the associated GHG emissions increase significantly out to 2050 as a result of the incremental diffusion of new gas sources with higher upstream emissions. The GHG emissions data used for different gas supply sources in this paper ranged between 1.5 and 31 gCO₂eq/MJ. This largely overlaps with findings of the SGI review [10], which estimated that GHG emission associated with gas supply chains could range between 2 and 42 g CO₂eq/MJ. The data used in this assessment mainly lies in the lower end of this range, as only the most commonly used supply routes for each gas source were examined. Variation may also be the result of slightly differing system boundaries between studies, and to a lesser extent due to the lower GWP of methane used in this paper (in line with IPPC AR4 GWPs). The central estimate GHG emission intensity of these three supply mixes ranged roughly between 13 and 16 gCO₂eq/MJ in 2050, rising from the baseline of just under 5 gCO₂eq/MJ in 2012 (see Fig. 2). The high biogas dependence mix (supply mix 2) had the highest associated GHG emissions, representing a 3.4 times

increase in GHG emissions on the 2012 UK gas mix. The high shale gas penetration mix (Supply 1), had the lowest central estimate of associated upstream emissions in 2050, representing a 2.7 times increase on emissions.

Russian pipeline gas has the largest associated uncertainty range of all the sources examined. This range was largely due to disparity in reported methane leakage rates in this region (ranging from 0.9% to 3.3% of gas transported) [56]. For LNG and shale gas, the range in fugitive methane emissions rate also proved to be a key parameter, accountable for much of the uncertainty [38–43]. In contrast, the range in GHG emissions associated with biomethane production, was primarily due to the variance in yield from feedstocks available [35,41]. Since these supply routes all play a significant role in the future gas supply scenarios examined here, there is a considerable uncertainty range associated with all three mixes.

3.2. Life cycle GHG emissions of the future UK electricity system

The life cycle GHG emissions of the transition pathways paired with the three future gas supply mixes are presented in Figs. 4–6 for MR, CC and TF respectively. The results are compared with the baseline results (using the 2012 gas mix) in these figures, to determine the impact of the gas supply transformation on the life cycle GHG intensity of the UK ESI. The emissions have been broken into upstream gas, upstream other, and direct fossil emissions, to enhance the interpretation of the results. The upstream gas emissions are the GHG emissions associated with the gas production processes for the given gas supply (as highlighted in the gas supply box in Fig. 1). 'Upstream other' emissions specified here, are all the GHG emissions upstream relating to the power sector (such as emissions associated with upstream coal and biomass supply, upstream materials and processing related with power generators construction, and their transport to site), excluding the upstream gas emissions. Direct fossil emissions are the GHG emissions resulting from the combustion of fossil based gas sources.

The gas supply evolution out to 2050 was seen to be influential over the cumulative results for all three pathways (see Figs. 4–6),

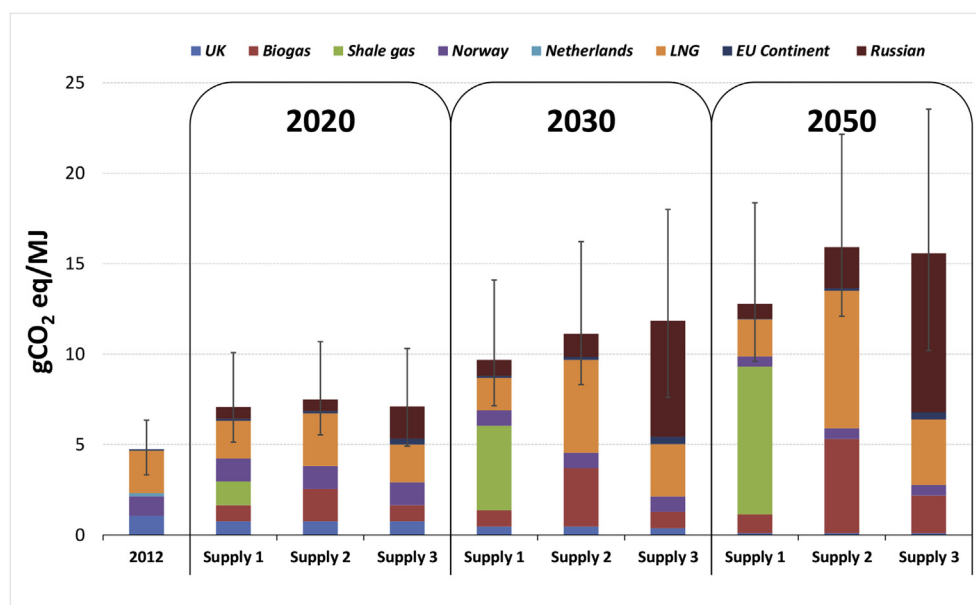


Fig. 3. GHG emissions intensity of potential future UK gas supply mixes per MJ of fuel delivered. [Error bars represent the overall uncertainty range associated with each gas mix as discussed in Section 2.1].

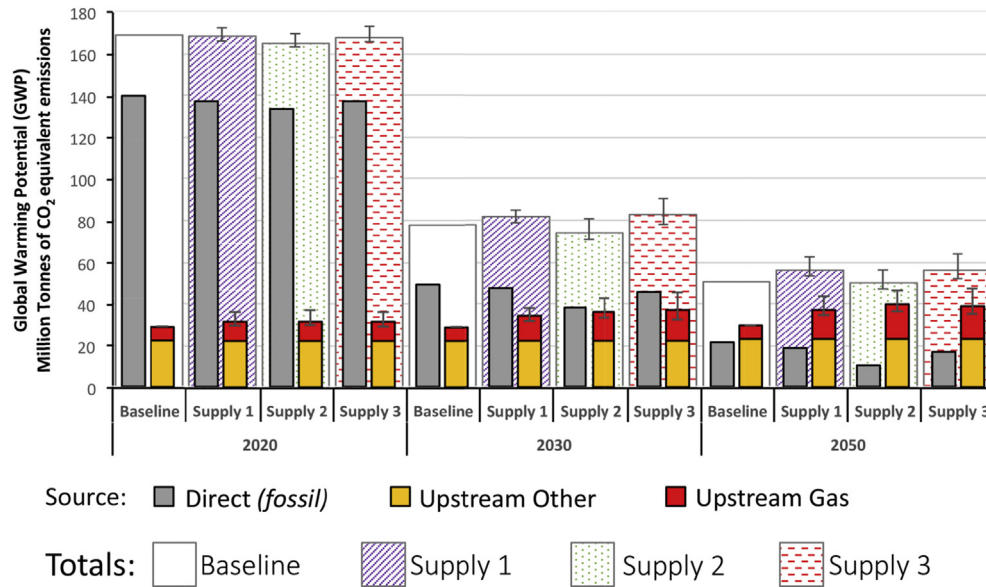


Fig. 4. Total life cycle GHG emissions for the Market Rules (MR) Pathway when paired with the three future gas supply mixes. These emissions are then broken down into direct fossil, upstream other and upstream gas respectively. [Error bars represent the uncertainty range associated with each gas mix as discussed in Section 2.1].

but the degree in which they vary dependent on the gas supply mix employed. The high shale gas supply (Supply 1) resulted in the highest central estimate life cycle GHG emissions for all transition pathways, whilst the high biomethane and LNG supply (Supply 2) resulted in the lowest. The high Russian gas supply (Supply 3) life cycle emissions for the three pathways were only marginally lower than the high shale gas supply. Despite having the highest associated upstream emissions, the central estimates for all three pathways, paired with the biomethane and LNG mix (Supply2), in fact observed the lowest overall life cycle emissions, demonstrating the importance of taking a whole life cycle perspective. This was the result of a reduction in direct fossil GHG emissions owing to greater penetration of biomethane. In contrast, the *Thousand Flowers* (TF)

pathway had similar results for all three gas supplies (see Fig. 5). This pathway is less dependent on gas generation in 2050 compared to MR and CC. Biomethane CHP is the dominant fuel based technology under the TF pathway, providing backup to the more intermittent technologies. The changes in GHG emissions in TF were, therefore, largely the result of upstream emissions related to biomethane production, with only relatively minor influence from other gas sources.

The *Market Rules* (MR) pathway, when paired with Supply 1, gave rise to an increase in central estimate life cycle emissions of 6 million tonnes of CO₂eq emissions by 2050 (see Fig. 3), while the *Central Coordination* (CC) pathway rose by 4.5 million tonnes of CO₂eq emissions (see Fig. 4), representing nearly a 10% and 14% rise

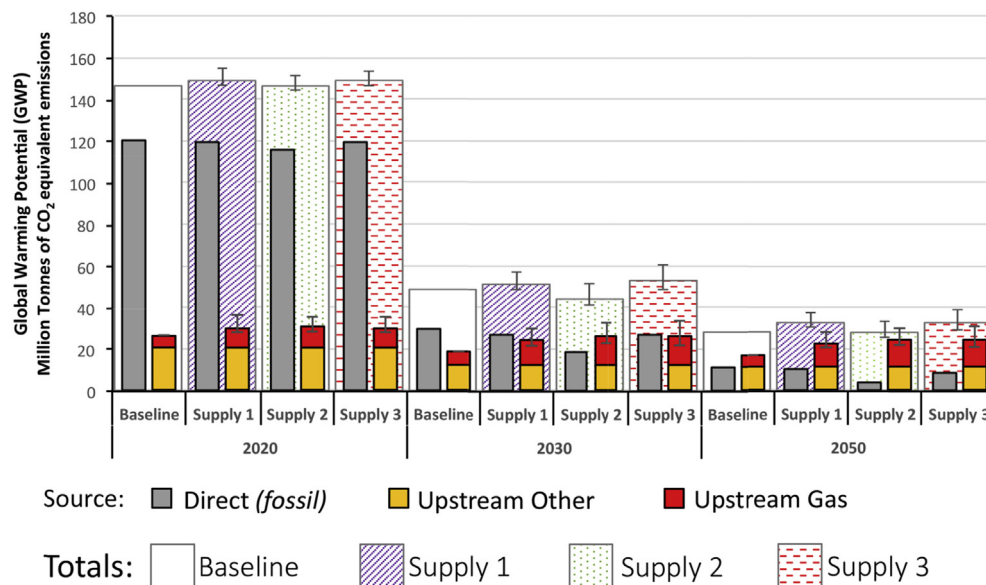


Fig. 5. Total life cycle GHG emissions for the Central Coordination (CC) Pathway when paired with the three future gas supply mixes. These emissions are then broken down into direct fossil, upstream other and upstream gas respectively. [Error bars represent the uncertainty range associated with each gas mix as discussed in Section 2.1].

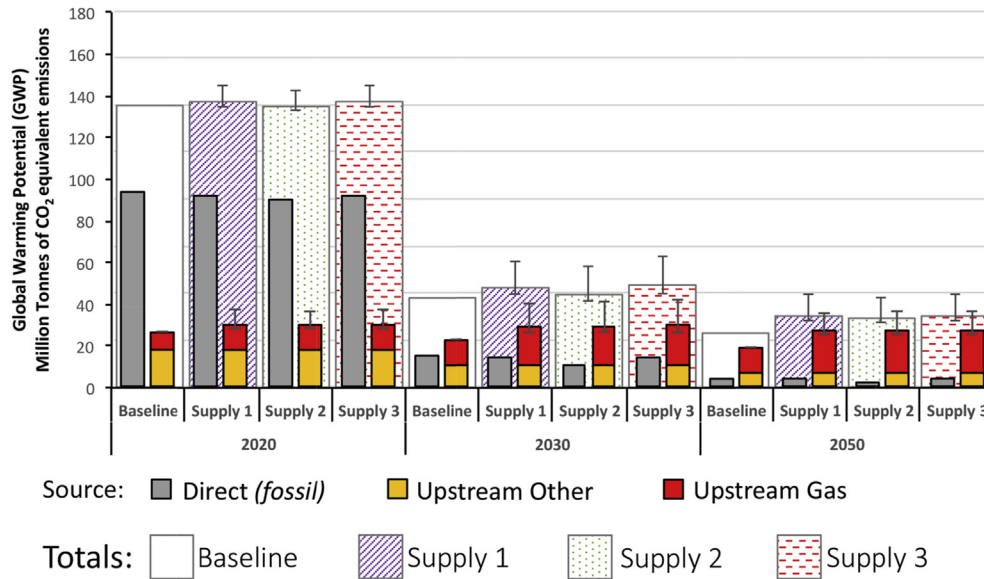


Fig. 6. Total life cycle GHG emissions for the Thousand Flowers (TF) Pathway when paired with the three future gas supply mixes. These emissions are then broken down into direct fossil, upstream other and upstream gas respectively. [Error bars represent the uncertainty range associated with each gas mix as discussed in Section 2.1].

above the baseline respectively. The central estimate life cycle emissions for the TF pathway, when paired with supply 1, experienced the greatest rise in GHG emissions of 7.3 million tonnes of CO₂eq emissions (a 24% rise above baseline), due to the increase in upstream emissions associated with biomethane out to 2050. This pathway only features a moderate level of gas-fired CCS generation by 2050, and therefore does not experience the same reduction in direct emissions as the other two pathways. In contrast, when paired with the Supply 2 (having the highest biomethane penetration), the lowest level of GHG emissions can be observed for all three pathways (see Figs. 3–5). MR and CC emissions drop by 0.5 and 0.3 million tonnes of CO₂eq emissions in 2050, while TF pathway emissions rose by 6.3 million tonnes above the baseline.

3.3. Impacts of gas supply transformation across life cycle stages

The gas supply transformation was seen to have varying impacts on different life cycle stages of electricity generation, from increase

upstream emissions, to reducing direct fossil emissions through the influx of biomethane. For all three pathways, upstream emissions associated with gas supply were shown to increase considerably, due to the greater penetration of new gas sources with higher associated upstream emissions. The central estimates for upstream emissions associated with the gas supplies ranged from 11 to 20 million tonnes of CO₂eq emissions in 2050, accounting for 25%–70% of total electricity sector emissions by the end of the transition. This represents an increase of between 6 and 8 million tonnes of CO₂eq emissions above baseline gas-related upstream emissions.

Direct fossil emissions were seen to reduce substantially (see Table 3), from both fuel switching from natural gas to biomethane, and also the sequestering of biogenic emissions associated with biomethane-fired power generation with CCS. Reductions in the central estimate direct fossil emissions from the baseline, ranged between 0.3 and 1.6 million tonnes of CO₂eq emissions for the TF pathway, and between 2.1 and 10.6 million tonnes of CO₂eq emissions for its MR counterpart in 2050. Supply 2 and 3 exhibited this offset of emissions most strongly, with a share of 25% and 10% of biomethane in the gas supply mix by 2050 respectively. Nonetheless, more absolute emissions reduction was experienced in 2030 when gas-fired CCS played a more significant role in the pathways, despite lower penetration of biomethane in the gas supply mix.

The gap between direct fossil and total emissions, and hence the perceived and real GHG performance of the UK ESI, were seen to increase from the baseline system for each year examined as a result of the gas supply transformation. The absolute change in GHG emissions for each life cycle stage between the baseline gas supply and that of the Supply 1–3, for all three pathways, is shown in Fig. 7, demonstrating the vulnerability of the UK ESI performance to the dynamics in gas supply and markets.

4. Discussion and policy implications

The implications of a future UK gas supply transformation have been examined in this paper by developing three gas supply mix scenarios to explore the potential impact on climate change of the future UK ESI. Each mix represents different UK gas futures, dominated by particular gas resources. Supply 1 consists mainly of

Table 3
Reduction in direct emissions from baseline for the Transition Pathways for 2020, 2030 and 2050.

Million tonnes of CO ₂ eq emissions				
Year	Supply	MR	CC	TF
2020	Supply 1	3.29	1.25	1.90
	Supply 2	6.59	4.28	3.80
	Supply 3	3.29	1.25	1.90
2030	Supply 1	1.73	2.82	1.42
	Supply 2	11.10	11.93	5.11
	Supply 3	3.08	3.31	1.42
2050	Supply 1	2.11	1.59	0.32
	Supply 2	10.55	7.95	1.60
	Supply 3	4.22	3.18	0.64

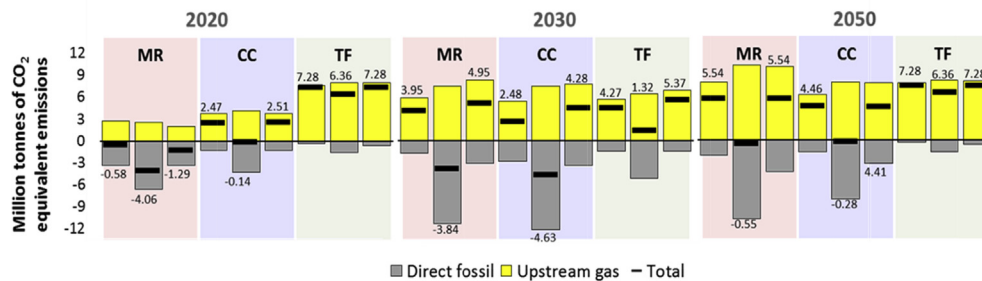


Fig. 7. The absolute change in GHG emissions for different life cycle stages of electricity generation for the three Transition Pathways. The graph shows the disparity between baseline gas supply results (where zero represents the baseline) for the pathways and the results for supply 1–3 (from left to right).

shale gas, Supply 2 is dominated by both indigenous biomethane and LNG imports, whereas Supply 3 is dominated by Russian natural gas imports. The 2012 gas mix used in the baseline assessment of the Transition Pathways was substituted with these three gas mix scenarios to investigate their impact on the overall GHG intensity of the UK ESI. This work builds on the attributional life cycle GHG emissions assessment of the technological trajectories of these Transition Pathways [17]. Together, they form a more comprehensive life cycle GHG assessment of the system than has been previously available which will could help to inform future decision-making.

Several significant conclusions can be drawn from the transformation in GHG intensity associated with the electricity supply in response to the gas supply evolution. The UK ESI GHG performance will become more dependent on gas supplies from far away regions with emissions of greater uncertainty. The GHG emissions associated with the gas supply chain were found to range considerably between routes; between 1.5 and 31 g CO₂eq/MJ. These results largely coincide with findings of a comprehensive review of gas supply chain GHG emissions conducted by SGI [10], based at Imperial College London. The gas supply chain GHG emissions in this paper stretched at the lower end of range estimated by the SGI review of between 2 and 42 g CO₂eq/MJ. Only the more commonly used routes were assessed in this paper, resulting in a slightly lower range, while the SGI look at a wider assortment of potential routes.

Central estimates suggest that total life cycle emissions of the UK ESI will increase, except where the penetration of biomethane is sufficient to offset rising upstream emissions. When the pathways were paired with Supply 1 (the most impactful mix), the central estimate of total emissions were seen to rise between 4.5 and 7.3 million tonnes of CO₂eq emissions by 2050, representing a 9.9% and 24% rise respectively compared to the baseline system. Direct emissions were seen to fall for all pathways, through the penetration of biomethane, particularly when used in conjunction with gas-fired CCS. The disparity in GHG emissions between the baseline gas supply and that of the Supply 1–3 for the pathways for each life cycle stage is shown in Fig. 7, demonstrating the vulnerability of the UK ESI performance to the dynamics in gas supply and markets.

Since decarbonisation of the electricity system is a critical climate change policy in both the UK and globally, better monitoring and mitigation of upstream emissions is needed to ensure that significant rises in GHG emissions are avoided. The UK National GHG Inventory only accounts for emissions that occur within the national boundary, although there still remains indirect emissions unaccounted for that occur overseas. Full accounting of gas related emissions is of particular importance in the UK, as its gas supply is set to undergo a large transformation over the coming years as domestic natural gas diminish [16]. Failure to account from these

emissions, could make the electricity produced seem less impactful than reality, and could induce greater usage, resulting in adverse consequences that would not have been accounted for under current legislation.

A significant proportion of upstream GHG emissions were the result of fugitive methane emissions during production, transportation and distribution from all gas production routes. The range of fugitive methane rates reported in literature was responsible for much of the uncertainty associated with the gas sources. These fugitive emissions can be minimised with the correct procedural measures. This is increasingly critical in light of the most recent report by the IPCC which called for an increase to the GWP of methane from 25 to 34 gCO₂eq over a 100 year time horizon [37] for biogenic methane, and 36 over a 100 year time horizon for fossil methane, implying that it is a far more potent GHG than previously realised. The increase in gas upstream emissions shown here would be more severe should this new GWP for methane be applied. Reporting of disaggregated data in future work in this area, including a breakdown of GHGs emitted, would greatly enhance studies of this nature, and facilitate the adoption of the most current climate science thinking, and also assist greater scrutiny of key parameters of gas supply chains, such as transport distances and fugitive emissions rate.

The underlying data for shale gas GHG emissions were from US-based studies, and should only be considered 'indicative' until UK operational data becomes available. The Shale gas industry is now well established in North America; but transparent GHG emissions data is still scarce. It is imperative that accurate emissions data is collected at the earliest stages of UK operations, in order to assess the disparity with North American counterparts. Equally there are large uncertainties in GHG emissions associated with biomethane, since its feedstock could vary significantly over time, or from one season to the next.

This study highlights the vital role biomethane could play in the gas supply future in order to limit GHG emissions. Its inclusion in the supply mixes proved essential in offsetting the otherwise rising upstream emissions, particularly for MR and CC pathways that contain greater gas-fired generation. The high shale gas supply (Supply 1) was disadvantaged by the low penetration of biomethane in the mix (see Figs. 4–6), resulting in the highest cumulative emissions for the UK ESI for all three Transition Pathways. Shale gas would assist in securing the UK's security of supply, but could hinder the growth of biomethane. There is little doubt that increased availability of low cost gas through the development of a UK shale gas industry could fundamentally re-order UK energy policies. The importance of developing and maintaining support for a strong UK biomethane production industry, regardless of the exploitation of shale gas, has clearly been demonstrated by the

present study.

Both MR and CC pathways rely substantially on CCS to reduce their GHG emissions. Reduction in direct fossil GHG emissions was seen to be particularly large when CCS is used in conjunction with the combustion of biomethane. In the absence of large-scale CCS, the use of gas as a transition fuel must be greatly reduced in order to adhere with carbon budgets. This work demonstrates the critical role of gas CCS in the future UK energy system, highlighting the need to replace and strengthen CCS funding rapidly, in light of the recent cancellation of one billion (£1 bn) pound funding for CCS in the UK [57].

The gas supply transformation that will be experienced in the UK over the coming years will have much wider over-arching environmental implications than GHG emissions alone. All future supply mixes scenarios rely on alternative gas supplies, such as shale gas and biomethane. Both resources can provide gas at lower life cycle emissions than some of their more traditional counterparts, such as LNG and Russian imports, although they pose other significant environmental risks. The nascent shale gas industry has received attention for its wider environmental impacts, such as groundwater and surface contamination, land contamination, water consumption and seismic impacts [58,59]. Similarly, biomethane production can result in large water usage, land degradation and land conflict with the food sector [60]. Such environmental trade-offs must always be managed comprehensively, expanding on the sort of sustainability criteria originally established for biofuels in, for example, the EU's *Renewable Energy Directive* [61].

As new energy policies advance, and changes are implemented to the current power system, it becomes necessary to not only consider today's benefits, but to also examine the long-term dynamics. Ensuring that transitions embarked on now, will continue to be advantageous into the future. Relying on gas as a transitional fuel may result in GHG emission lock-in, with emissions increasing further as upstream emissions rise over the coming decades. The UK benefited from substantial reductions in emissions in the 1990s during the "Dash for Gas", and consequential reduction in coal generation. However, a greater uptake of gas-fired generation cannot continue to deliver these same benefits into the future, particularly as it may impede the rate of deployment of low carbon technologies [4,62].

5. Conclusions

All three *Transition Pathways* had previously been shown to significantly reduce the associated life cycle GHG emissions of the UK electricity sector, but at varying degrees of success [17]. The development of these transitions (seen Figs. 4–6) have the greatest bearing on the total life cycle emissions of the UK electricity sector as a result of the various mitigation policies enacted across their timeline. One of the most effective step changes seen in these pathways was the incremental switching of coal to gas-fired generation. A similar strategy has been widely adopted by developed nations. The demand for gas is projected to rise in response to fulfilling this role as a bridging fuel to a low carbon future [4]; providing dispatchable back-up generation to balance the growth in renewables. As such, gas generation is anticipated to play a critical role in the UK energy future, further compounded by the recently announced complete phase out of coal generation by 2025 [48]. Concurrently, indigenous conventional gas production, already insufficient for the nation's needs, is set to diminish further which will result in a large transformation of the UK gas supply. This reshaping of the gas supply was shown in this paper to have considerable bearing on the life cycle greenhouse gas (GHG)

emissions of UK electricity generation (see Section 3.2) which is currently not fully addressed by legislation [17].

A key finding in this research was that the UK electricity supply industry (ESI) GHG performance will become more dependent on gas supplies from far away regions, with higher associated GHG emissions than the current gas mix; which are also subject to greater uncertainty (see Section 3.1). Overall, when the three gas supply mix scenarios were paired with the *transition pathways* (three low carbon electricity futures for the UK), central estimates suggest that total lifecycle GHG emissions of the UK ESI will increase compared to the baseline, unless the penetration of biomethane within the gas supply is sufficient to negate the rising upstream emissions. Upstream emissions were seen to rise substantially from the baseline by 2050, increasing by between 6 and 8 million tonnes of CO₂eq of additional GHG emissions (see Fig. 7). By the end of the transition, these gas-related upstream emissions accounted for between 25 and 70% of total electricity sector GHG emissions, compared to just 3% for the current system. The carbon credit afforded by the influx of biomethane (particularly when combined with CCS), led to a coinciding reduction in direct fossil emissions. Consequently, the gap between direct fossil and total GHG emissions for the UK ESI was seen to grow in response to the gas supply transformation. Hence the direct GHG intensity of UK electricity (its perceived performance) appeared lower for all three pathways than the baseline, despite total life cycle emissions (its real performance) being in fact higher for both the high Shale and the high Russian gas supply mix, or of a similar level for the high biomethane and LNG gas supply mix. These results demonstrate the importance of considering the comprehensive total lifecycle GHG impacts of electricity generation, rather than just direct fossil ('stack') emissions, when developing and implementing new decarbonisation policies.

In the absence of adequate support to develop both a strong carbon capture and storage [6] and biomethane production industry, the future of gas generation in the UK must be reevaluated. Gas cannot act as a bridging fuel without these technologies to help curtail GHG emissions, as the system would become locked into emissions far higher than required levels. The carbon credits associated with biomethane proved essential in offsetting the rising upstream emissions, particularly for the *Market Rules* and the *Central Coordination* pathways which contain greater gas-fired generation. Consequently, disadvantaged by the low penetration of biomethane, the high shale gas supply examined in this paper proved the most impactful; despite lower associated upstream emissions than its LNG and Russian gas counterparts. Most critically, particularly in light of a recent funding failure [6], extensive investment in new gas capacity in the UK should be deterred until CCS reaches maturity. Only when these technologies reach full scale deployment; both negating rising upstream emissions and curtailing direct emissions, can gas-fired generation truly play a part in the transition to a low carbon future.

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with other members of the Consortium (and its predecessor) made up of participants from nine UK universities. However, the views expressed here are those of the authors alone, and do not necessarily reflect the views of the collaborators or the policies of the funding body. The authors' names are listed alphabetically.

Appendix A

Three future gas mix scenarios were developed based on future trends in this paper. These mixes were developed for explorative means only, and do not attempt to predict the future or steer the future gas market.

A list of the main assumptions and background data used to develop the three gas supply scenarios used in this paper are set out below:

UK production and import dependency

- UK gas supply mix 2012 figures were taken from *Digest of UK Energy Statistics* 2013 [35].
- The UK Government's *Department of Energy and Climate Change* (DECC) projects that Britain will have a gas import dependency of 57% by 2020, and 76% by 2030 [63], which is also in line with the *National Grid* (NG) future scenarios [64].
- This import dependency was assumed for the high Russian gas scenario with a reduced dependency used for the other two supply scenarios due to growth in domestic supply.
- Import dependency could be reduced from 76% to 37% by 2030 should shale gas reach its potential [65].
- Imports are accounted for as net imports, but with same proportion of import dependency as stated in the *Digest of UK Energy Statistics* (DUKES) 2013 [35].
- Gas flows to the UK were projected to be broadly in line with domestic production trends in each particular exporting country.
- The number of fields expected to be in operation in UKCS post 2050 even out to 2060 according to *Oil and Gas UK* [66]. However, this will be at a relatively low production rate. It was assumed to supply only 5% of overall demand in 2050.

European gas imports

- Imports ceased from Netherlands after 2020, due to its indigenous production decline [50]. Indeed, the IEA [53] forecast that Netherlands would be a net importer by 2025.
- Norwegian gas imports into the UK reached peak by 2014 and declined thereafter [50].
- Norwegian gas imports for 2020 and 2030 were taken from NG 'Gone Green' scenario taken from their UK future energy scenarios work [64].
- In 2020, other EU imports were based on NG imports proposed in their 'Gone Green' scenario [64].
- An 87% increase in gas imports into the EU is anticipated between 2006 and 2030 to meet the growing deficit [67].
- The split between European and Russian gas was then based on import assumptions for Europe in 2020, 2030 and 2050.

Shale gas

- Shale gas moratorium assumed for both Supply 2 and 3 in this paper.
- Shale gas production in 2020 based on 'reference case' production assumptions in the Deloitte report on the potential of Bowland basin shale gas development [68].
- Shale gas could provide up to 46 years of gas based on assumptions made by the NG [64].
- Only domestic shale gas has been considered in this analysis, shale gas imported from Continental Europe has not been considered.

Biogas

- For Supply 1, biogas is not incentivised due to environmental pressures (such as land use), thus remains the same as at present; i.e. only produced for bio-waste management.
- Assumed baseline projection by NG [69] for biogas for Supply 1 and 3 in 2020, while its 'stretch' scenario was used for Supply 2. This stretch scenario is taken to be near maximum biogas potential of the UK.

Russian gas

- Russia remains the world's largest energy exporter, meeting 4% of global energy demand by 2035 [70].
- Russian gas was set as minimum of 2.4 billion cubic metres based on contract written by Centrica in 2012, they were set to start importing by October 2014 [71].
- In 2020, Russia gas is swing source in Supply 3 similar to that assumed for the analysis by Rogers [50], thus meeting the shortfall.
- The ratio in 2020 between European and Russian gas stays the same across all supply scenarios.
- Europe's gas import dependency is expected to rise from 60% to more than 80% by 2035 [72]. Therefore imports from the gas pipeline are split 1/3 European (indigenous) to 2/3 Russian-based gas in 2030, based on the projected decline in European gas production. Imports from the gas pipeline are split 20% European (indigenous) to 80% Russian-based gas for supply 3 in 2030, in accordance with this high Russian gas future.
- In 2050, Imports from the pipeline are split 15% European (indigenous) to 85% Russia-based gas for Supply 3, based on similar assumptions to those made for the 2030 supply extrapolated into the future. Russian gas was presumed to be the dominant imported gas source for Supply 3.

Liquefied natural gas

- LNG was assumed to grow slowly out to 2020, due to tightness expected in the market over the coming years as a result of greater Asian demand for gas [16].
- For Supply 1, LNG and pipeline gas imports were split 50/50 in 2030 and 2050, in the interest of diversity of supply.
- For Supply 2, LNG and pipeline gas imports were split 75/25 in 2030 and 2050, as LNG is dominated supply in this scenario.
- For Supply 3, LNG was seen to only grow slowly from its 2012 levels as LNG supply is constrained in this future.

Appendix B

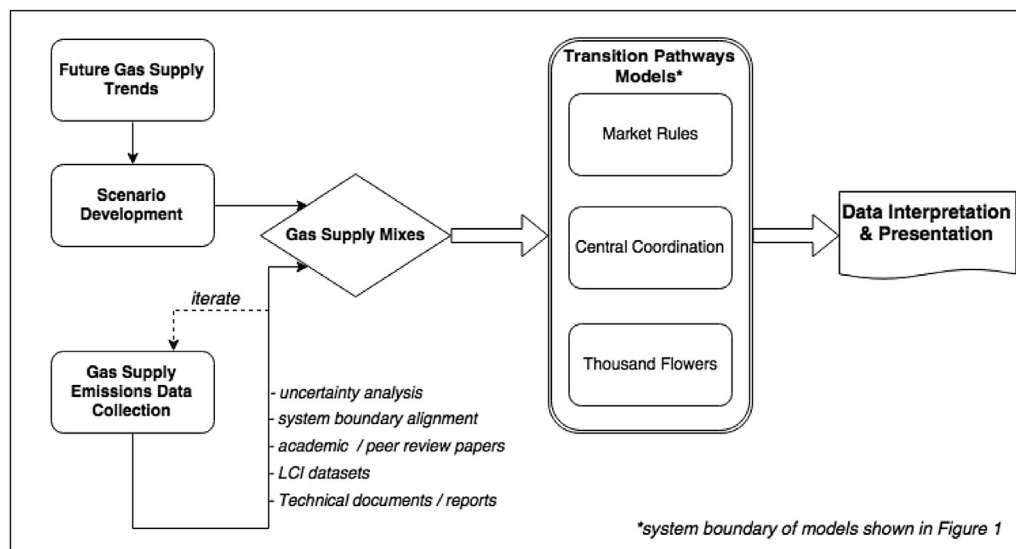


Fig. B1. Flowchart outlining dynamic LCA approach.

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